Applicants' Exhibit 17.0

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 04-0294

REBUTTAL TESTIMONY

OF

FRANK A. STARBODY

Submitted on Behalf of

ILLINOIS POWER COMPANY

July 20, 2004

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 04-0294

REBUTTAL TESTIMONY OF FRANK A. STARBODY

1. Q. Please state your name, business address and present position.

A. My name is Frank A. Starbody. My business address is 500 South 27th Street, Decatur, Illinois 62521. I am Vice President – Energy Supply & Customer Management for Illinois Power Company ("Illinois Power" or "IP").

2. Q. Have you previously submitted testimony in this docket?

A. Yes, I previously submitted direct testimony identified as Applicants' Exhibit 12.0 and an accompanying exhibit identified as Applicants' Exhibit 12.1.

3. Q. What is the subject matter of your rebuttal testimony?

A. I am responding to criticisms of various transmission and retail electric supplier ("RES")-related policies, practices and tariff provisions of Illinois Power that are contained in the direct panel testimony of the witnesses on behalf of Constellation New Energy, Inc., Direct Energy Marketing, Inc., MidAmerican Energy Company and Peoples Energy Services Company, Mario A. Bohorquez, Philip R. O'Connor, Ph. D. and Wayne Bollinger (collectively "BOB"). My testimony will only address policies, practices and tariff provisions of Illinois Power that are criticized by BOB. I am not addressing any policies, practices or tariff provisions of the Ameren Companies; these will be addressed by a witness or witnesses from Ameren. In addition, as a representative of Illinois Power, the entity that is being acquired in the reorganization that is the subject of this docket, I am not in a position to address whether Applicants can agree to adopt any of BOB's proposals following the closing of the acquisition. Any such commitments or declinations to adopt BOB's proposals will be made by witnesses from Ameren.

I will respond to a number of BOB's criticism and proposals that are directed at Illinois Power's Federal Energy Regulatory Commission ("FERC")-jurisdictional open access transmission tariff ("OATT") and at related policies and practices. By responding substantively to BOB's criticisms and proposals relating to IP's transmission tariffs, policies and practices, Illinois Power is not conceding that the Illinois Commerce Commission would have any authority to direct IP to modify any FERC-jurisdictional transmission tariffs, policies or practices.

As a final preliminary matter, I note that the Applicants are filing a motion to strike BOB's testimony. In light of the procedural schedule in this docket, it is necessary for my rebuttal testimony to be filed before the motion to strike will be ruled on by the Administrative Law Judge. The fact that I am submitting rebuttal testimony responding to substantive points in BOB's testimony should not be construed as waiving Applicants' motion to strike that testimony.

4. Q. BOB indicate that retail competition has developed more slowly in the IP service area than in the Commonwealth Edison Company ("CE") service area and suggest that there are no external factors that should cause this differential rate of retail competitive development. (BOB Testimony, pp. 4-5, 9-12) Do you agree?

A. I agree that there appear to be more RESs active in CE's service area, seeking to serve non-residential customers, than is the case in IP's service area. I note that to the best of my knowledge, at this time no RES has sought or obtained certification to serve residential customers in the service area of any Illinois electric utility, and thus no residential customer of any Illinois electric utility is purchasing electricity from a RES. I note that overall, based on the statistics reported by IP and CE to the Commission as of the end of May 2004 and posted on the Commission's web site, 33.7% of CE's eligible customer usage is taking delivery services whereas 33.5% of IP's eligible customer usage is taking delivery services. Further, 22.5% of CE's eligible customer usage is being supplied by RESs while 20.7% of IP's eligible customer usage is being supplied by RESs. One noticeable difference between the CE and IP service areas is the greater number of smaller non-residential customers taking delivery services in general and RES supply in particular in CE's service area. However, I do not agree that there are no differences between the CE and IP service areas that would contribute to the differential development of retail competition in the respective service areas.

5. Q. What do you see as differences between the CE and IP services areas that would contribute to the differential rates of development of retail competition between the two service areas?

A. The primary differences are the greater population density in general and the greater numbers and concentration of smaller non-residential customers (commercial customers) in the CE service area than in the IP service area. As a result, I would expect marketing and customer acquisition costs per customer acquired to be lower in CE's service area than in IP's service area. Further, the metropolitan Chicago area, served by CE, is simply a more attractive area to serve as a base of operations for a RES than is IP's service area which includes several widely-scattered cities none of which has a population greater than about 100,000 persons. Additionally, the CE area and northern Illinois has had a more liquid wholesale market (the "Into CE" or more recently, the Northern Illinois Hub) than southern Illinois which makes the CE service area more attractive to RES from that perspective.

Moreover, while at the time of enactment of the Customer Choice Law in 1997 and the start of the mandatory transition period with the accompanying retail rate freeze the residential base rates of IP and CE were comparable, IP's industrial rates were lower than those of CE. Subsequently, residential customers of both CE and IP have received a statutorily-prescribed 20% aggregate reduction in base rates which presumably has contributed to the lack of interest by RESs in seeking to market to residential customers in either service area.

Finally, IP believes that a significant factor affecting the relative degrees to which RESs have gained retail customer load in the IP and CE service areas is that IP's delivery services and market value tariffs are more accurate for a specific customer at a specific point in time than are the CE tariffs, with the result that there are fewer embedded rate design inefficiencies in IP's tariffs that can be exploited by a RES. IP uses customer load profiles differentiated by customer size and business classification type in determining market values, and calculates the market value applicable to a customer closer in time to when it will be effective than is the case under the CE tariffs. IP's tariffs and procedures are more likely to result in a market value for the individual customer which represents both the current market at the time the customer is shopping, and the customer's individual load characteristics, than is the case if the market value is calculated farther in time from its effective date and if less customer-specific load profiles are used. Any resulting reduction in accuracy from such rate design inefficiencies (as compared to the IP approach) will result in greater savings potential for some customers and less (or no) savings potential for other customers, thereby providing some customer segments with a greater incentive to switch to RES supply while other segments may have reduced incentive to switch to RES supply as well as less advantage to be gained from electing PPO service.

6. Q. BOB state that much of the competition in IP's service area has been "legacy special contracts" and Power Purchase Option ("PPO") service enlistment, and that there is "overreliance" on PPO service by IP customers. (BOB Testimony, p. 10) Do you have any comments?

A. Yes. Illinois Power has had a number of tariffed individual contracts with larger non-residential customers, but as a result of electing independent distribution company status, IP is no longer entering into such contracts. As a result, the number of such contracts is dwindling as existing contracts expire. At present IP has only four such contracts remaining. One of the four remaining contracts expires in August 2004, a second expires in September 2004, a third is presently on a year-to-year basis and can be terminated by either party by giving 12 months notice prior to the end of an annual term, and the fourth is not a power supply contract but rather a contract for joint ownership and use of backup diesel generators located at the customer's premises.

Although not mentioned by BOB, Illinois Power also entered into a number of competitive service contracts with non-residential customers during the

1998-2001 period. Again, as a result of electing independent distribution company status, IP is no longer entering into such contracts, and so the number of such contracts is dwindling as existing contracts expire. By December 31, 2004, only 26 of these contracts will remain in effect.

Illinois Power's view is that customers who entered into tariffed special contracts or competitive service contracts with IP after enactment of the Customer Choice Law received benefits of customer choice in the manner selected by the customer. Further, these customers have the opportunity to seek alternative supply options as their contract terms expire.

With respect to the PPO, this is a service option that Illinois Power is mandated by statute to offer to nonresidential customers. IP has offered PPO service as a tariffed service as required by the Public Utilities Act and orders of this Commission. Illinois Power would acknowledge that the PPO offering is a power supply service offering that is relatively risk-free for the customer and therefore has been found to be attractive by many nonresidential customers. IP also acknowledges that there would likely be greater opportunities for RESs in IP's service area if the PPO did not exist, but as I noted, this service offering is mandated by statute. Illinois Power, with Commission approval, has implemented changes to Rider MVI to improve the accuracy of the market value determination; these changes have the effect of increasing the "market value" of power and energy and thereby decreasing IP's transition charges while increasing the PPO price relative to the original MVI tariff. Indeed, if the customer's transition charge falls to zero, PPO ceases to be an option for the customer.

7. Q. Turning to specific transmission and retail distribution policies, practices and tariff provisions criticized by BOB, have BOB asserted that Illinois Power has violated any applicable federal or state statutory provisions or any applicable regulations or orders of the FERC or of this Commission?

A. No, they have not to my knowledge.

8. Q. BOB state that unless the Commission addresses what BOB describe as "unnecessary noncompetitive tariff and transmission-based obstacles, Ameren's proposed acquisition of Illinois Power cannot be interpreted as promoting the development of both wholesale and retail competition." (BOB Testimony, p. 7) Is it your understanding that in order to approve the proposed reorganization that is the subject of this docket, the Commission must find that the reorganization will promote "the development of both wholesale and retail competition"?

A. No, it is not. I am advised by counsel that in order to approve the proposed reorganization, the Commission must find that "the proposed reorganization is not likely to have a significant adverse effect on competition in those markets over which the Commission has jurisdiction." IP's policies, practices and tariff provisions that BOB criticize are currently in place and if, following the closing of the reorganization, they remain in place (which, as I noted earlier, is ultimately a decision to be made by Ameren), it does not seem to me that one could conclude that the reorganization has had an adverse impact on competition.

10. Q. Please explain the basis for Illinois Power's transmission service policies of allowing a RES a maximum aggregate reservation for Network Integration Transmission Service ("NITS") of 25 MW without designating a specific end-use

customer, allowing a NITS reservation request to be placed a maximum of 6 months prior to commencement of the service, allowing a maximum NITS reservation term of 13 months and requiring that a unit-specific resource be designated for NITS, which BOB discuss at pages 14-15 of their testimony.

A. First, I note that there is no cap on the amount of NITS that a RES can reserve to serve designated end-use load. The 25 MW cap on NITS reservation applies only to reservation of NITS capacity without designating end-use load to be served. As BOB acknowledge (BOB Testimony, p. 15), when a RES holding 25 MW of NITS reservation designates end-use load to be served from that reservation, the designated amount of end-use load is removed from the 25 MW NITS reservation therefore enabling the RES to reserve additional NITS to again reach the aggregate reservation of 25 MW without designated end-use load.

These policies are reasonable limitations on the ability of an individual RES to tie up an unreasonable amount of finite transmission capacity for an indefinite period to the detriment of other potential transmission users. Without these limitations, a RES could obtain a virtually unlimited firm right to use transmission service on a designated path via NITS, without having any load under contract. Absent these limitations, there would be virtually no cost to the RES to reserve a large amount of NITS capacity, because under the FERC-mandated OATT, NITS is charged for based on the transmission customer's actual use of the system (contribution to peak demand), not on the size of the customer's reservation. However, placement of a NITS reservation on the OASIS system with a specified point of receipt and point of delivery reduces the amount of NITS available to other market participants, particularly if the reservation involves a constrained interface. This in turn may preclude other market participants from being able to access lower cost resources to serve their contracted load or, in the case of generators, to sell their output into markets that will produce a higher price for the generators. Such preclusion could itself be detrimental to competition. Illinois Power's policies of allowing a RES to reserve up to 25 MW of NITS without designating an end-use customer to be served, to reserve the NITS capacity up to six months in advance of the planned commencement of service, and to hold NITS reservations for a maximum of 13 months, represent a reasonable balance and compromise of all market participants' interests. These policies were established after discussions and negotiations with a number of RESs.

I disagree with BOB's assertion at page 16 of their testimony that the 25 MW cap on NITS reservation without designated end-use load increases the RES's risks and costs, particularly given BOB's focus on the lack of RES service to smaller- to medium-sized nonresidential customers in IP's service territory. It seems to me that by holding a NITs reservation of 25 MW (or even less) that is not committed to specific load, the RES has ample transmission capacity reserved to serve such customers, as and when the RES is able to place them under contract.

11. Q. BOB contend that IP's transmission service policy of requiring a unit-specific resource to be designated for NITS should be eliminated and that IP should instead accept firm liquidated damages ("LD") contracts from the RES to satisfy

the requirement for a designated network resource. (BOB Testimony, p. 17) Do you agree?

A. I do not agree that IP should accept LD contracts that do not have a specific generation resource or resources associated with them. First, let me explain that the requirement for a transmission customer to designate a "network resource(s)" in order to take NITS is a requirement of the FERC-mandated OATT. BOB do not appear to be questioning this requirement. Rather, the issue they raise is whether the transmission user should be required to designate a specific, identified generation resource (owned or contracted for) in order to be able to receive NITs, or on the other hand whether the RES should be able to satisfy the network resource requirement by designating an LD contract that does not have a specific generation resource associated with it. This type of LD contract is sometimes referred to as an "into" contract meaning that it does not designate a specific generation resource but is only a contract for delivery of capacity "into" a specified location or control area. (There are also LD contracts that do have a specific resource or resources associated with them, and IP accepts such contracts for NITS reservation purposes.) An LD "into" contract is a contract with a supplier for a specified amount of capacity under which the supplier agrees to either deliver the contracted-for capacity or pay the buyer a specified amount of compensation (liquidated damages). Under an LD "into" contract, the supplier is not required to identify and commit a specific generation resource from which the contracted-for capacity will be provided. In fact, physical delivery of capacity cannot be compelled under an LD "into" contract; the supplier is entitled to elect to pay the liquidated damages instead (even if the supplier in fact has the generation capacity available – the supplier could simply elect to sell that capacity into a different, higher-priced market and pay the liquidated damages). In other words, an LD "into" contract is essentially a financial product, not a commitment of capacity from a specific, identified generation resource.

To allow an LD "into" contract to be used to satisfy the network resource requirement without identification of an actual generation resource would threaten system reliability, make it more difficult for transmission owners and security coordinators to ensure that adequate capacity exists to satisfy load requirements, and allow the parties to the LD "into" contract to shift risk to the generation provider of last resort in the area in which the RES' load is located. As I have indicated, LD "into" contracts do not represent a commitment of specific supply resources (or transmission resources or transmission path), and the supplier under an LD "into" contract is not required to use or obtain firm resources to meet its obligations. Thus, the use of a set of financial rights (an LD "into" contract) rather than physical generation resources to satisfy the network resource requirement may degrade system reliability because load serving entities will not have the right to specific physical generation capacity, but only rights under a financial instrument that merely shifts price risk. LD "into" contracts do not provide the same level of system reliability as a specific, designated generation resource because the LD "into" contract does not provide a right to a specific source of capacity and energy.

I note that LD "into" contracts do not satisfy the reliability requirements established by the Mid-American Interconnected Network ("MAIN"), the North American Electric Reliability Council ("NERC")-member regional reliability council for IP's service area, for operating reserve or the calculation of capacity reserve margins in supply adequacy audits. This fact, and the fact that LD "into" contracts represent a weaker standard of reliability, have been recognized by Commission Staff witnesses in previous dockets. I should also point out that IP requires all transmission customers for NITS to designate specific generation resources, not LD "into" contracts, as their network resources; this policy is not applicable only to RESs.

To allow the designation of LD "into" contracts as network resources would also threaten system reliability by interfering with the ability of the transmission provider or reliability coordinator to accurately determine if there is sufficient capacity available to satisfy load requirements. The transmission provider or reliability coordinator must be able to make reasonable assumptions regarding the level and location of load in the control area and the amounts and locations of resources available to serve that load, at peak conditions. If a portion of the resources consists of LD "into" contracts, it generally cannot be known what the actual source of capacity and energy is until the day immediately prior to delivery (assuming the supplier actually elects to deliver capacity under the LD contract).

Further, to allow transmission customers to designate LD "into" contracts rather than specific generation resources as network resources for NITS may lead to inaccurate determinations of available transmission capacity ("ATC"). If, for example, a NITS customer were to designate an LD "into" contract as a network resource, the transmission provider (IP) would reduce its ATC by the amount of capacity viewed as necessary to support the customer's transaction, regardless of whether the customer intended to use that resource or even to provide the power at all. As a result, the amount of transmission capacity determined to be available along a given transmission path or on the transmission system as a whole will be reduced, making that capacity unavailable for other uses. This outcome not only affects those market participants making deliveries on the transmission provider's system, but also reduces the ability of market participants to obtain access to that transmission system to deliver power to, or take power away from, adjoining systems. The overall result is that other market participants are unreasonably denied access to transmission service.

12. Q. In your preceding answer you made reference to the "reliability coordinator". Please explain the role of the "reliability coordinator."

A. A reliability coordinator is responsible for the reliable operation of the bulk electric system, typically on a regional basis, in accordance with NERC practices. The reliability coordinator has the authority to act, or to direct actions to be taken, by other operating authorities within its area in order to preserve the integrity and reliability of the bulk electric system.

13. Q. BOB also criticize the policy of requiring and conducting system impact studies in connection with firm transmission service requests and contend that system impact studies should not be required for transmission service from generation

resources located within the "MISO [Midwest Independent Transmission System Operator, Inc.] footprint" to load located within the MISO footprint, and that designated network resources should be reciprocally accepted by control areas throughout MISO. (BOB Testimony, p. 18) What is a system impact study?

A. A system impact study determines if there is sufficient available transmission capacity to accommodate a given firm transmission reservation request. The study evaluates the ability of the transmission system to reliably accommodate the transmission of energy from a generation resource to a designated load or loads without causing unacceptable impacts (for example thermal loading problems, low voltages or instability) on the transmission systems of all impacted parties.

14. Q. Do you agree with BOB's position that a system impact study should not be required when the generation resource and the load to be served are both located within the "MISO footprint" and that designated network resources should be reciprocally accepted by control areas throughout MISO?

A. No. BOB's proposal raises reliability concerns. The "MISO footprint" covers a territory that ranges from Manitoba, Canada to Ohio. A critical component in the designation of a network resource is its ability to actually be able to serve the intended load. To assume that generation from a resource located anywhere in the "MISO footprint", e.g., Manitoba or northern Wisconsin, can in fact be delivered to an intended load located anywhere else in the "MISO footprint", e.g., southern Illinois, without impacting system reliability or the service to other transmission users, without conducting a study, is unrealistic.

15. Q. BOB state that there are inconsistent definitions of energy peak periods in Illinois Power's bundled and unbundled tariffs. (BOB Testimony, p. 17) Please state whether this is correct and if so why there are different definitions of energy peak periods in the bundled and unbundled tariffs.

A. I assume that BOB are referring to the fact that the on-peak period as defined in the Standard Terms and Conditions of IP's retail electric tariff is 10 AM to 9 PM weekdays, while the on-peak period as defined in IP's Rider MVI is 6 AM to 10 PM weekdays. (There may be other minor differences relating to which holidays are defined as "off-peak" under each tariff.) The on-peak period in IP's bundled tariffs is long-established and was based on analyses of system load that showed that system peak conditions are most likely to occur between the hours of 10 AM to 9 PM. The on-peak period in Rider MVI is tied to the definition of the standard "Into Cinergy HUB" product that is used to determine the forward market prices to set market values under Rider MVI. This tariff provision has also been approved by the Commission, most recently in Docket Nos. 00-0259/00-0395/00-0461 (Cons.) (2001). A subsequent case involving IP's MVI tariff, Docket Nos. 02-0656/0671/0672/0834 (Cons.) (2003), resulted in revisions to other provisions of Rider MVI but not to the provisions defining the on-peak and off-peak periods.

16. Q. BOB express concerns about the energy imbalance provisions in IP's OATT and argue that IP should adopt energy imbalance provisions like those formerly used by CE before it became a member of the PJM RTO. (BOB Testimony, pp. 19-24 and 26-27) Do you agree with BOB's comments?

A. No. Illinois Power's energy imbalance provisions are part of IP's FERC-approved OATT. These provisions are the result of a negotiated settlement entered into in 2000 at the conclusion of a lengthy FERC tariff proceeding, among IP, the Illinois Commerce Commission, various wholesale customers in Illinois, the Illinois Industrial Energy Consumers ("IIEC") and several RESs including MidAmerican Energy Company and New Energy Midwest (a predecessor company of Constellation New Energy). That case and the settlement negotiations resulted in introduction into IP's energy imbalance tariff of several provisions that had been advocated by RESs and other market participants.

Illinois Power, as the transmission provider, is also the provider of energy imbalance service. This means that in the case of under deliveries into the IP system, IP must supply additional energy, while in the case of over deliveries into the system, IP may be unable to fully use generation resources and energy that it has contracted for to serve its own retail load and to meet other load-serving obligations. Either situation imposes costs on Illinois Power, as well as (depending on the severity of the imbalance) threatening system reliability. BOB seem to ignore this fact, and to ignore that the energy imbalance provisions are not designed to be a source of supply for RESs and other market participants. Regardless of whether a RES' imbalance is an "occasional" incorrect schedule "due to operational issues" or due to force majeure events or other factors beyond the RES' control (BOB Testimony, p. 27), the impact on the transmission provider and the transmission system is the same as an imbalance of a market participant that "frequently schedule[s] incorrectly." (BOB Testimony, p. 27)

Illinois Power's current energy imbalance provisions in its OATT are designed to provide appropriate economic incentives to RESs and other market participants to schedule their loads and deliveries carefully, and to bear appropriate cost consequences if they fail to do so.

Illinois Power specifically rejects the suggestion that energy imbalance charges and credits should be equal to the transmission provider's out-of-pocket costs except in the case of particularly egregious imbalances (25% as used in the former CE provisions advocated by BOB). (BOB Testimony, pp. 20-21) Such a provision provides no incentive to the RES to schedule correctly and in fact encourages the use of energy imbalance as a source of supply or as a means to dump excess energy at a market price. With respect to BOB's suggestion that the tolerances or bands in IP's energy imbalance provisions are too narrow compared to the tolerances in the former CE energy imbalance provisions (BOB Testimony, pp. 21, 26), what is appropriate for CE's system in this regard is not appropriate for IP's system. CE's system is several times larger than IP's system and this provides CE (as the transmission provider) much greater latitude to absorb imbalances and load swings.

17. Q. Please respond to BOB's criticism that Illinois Power does not provide detailed calculations of transmission and transmission-related costs, together with the total settlement bill including a breakdown of hourly imbalance costs and penalties, within 45 days following the end of the month being billed. (BOB Testimony, p. 28)

A. BOB's position that Illinois Power should be expected to provide this information within 45 days is unreasonable, for several reasons. First, many of the necessary billing components must first be obtained (or will need to be obtained) from MISO. Second, while 45 days after the end of the month may seem like a long time to one unfamiliar with the transmission billing process, in fact it is not a long time in context. For example, not all meters are read at the end of the calendar month, but rather meters are read on one of 21 monthly cycles that are spread throughout the month. In order to prepare and issue the transmission bills for a particular month (such as January), all necessary data for the month of January must first be gathered (among other reasons because NITS is billed by allocating the transmission revenue requirement among all the transmission customers based on their respective contributions to the system peak – note that the transmission provider does not know until the end of the month if the system peak occurred on the first, fifteenth or thirty-first day of the month). This requires reading the meters of all retail customers that are served by each RES. Since some customer's meters will not be read until late in the following month (e.g., February 25), this basic data necessary to even begin the billing calculations is not available until approximately 25 days after the end of the month. In addition to performing the necessary calculations, IP's transmission billing process also includes various verification and validation steps, particularly if there are discrepancies indicated by the reported metered data. Illinois Power does attempt to release final monthly transmission billing information as soon as it is completed, rather than waiting for a certain time frame to pass following the end of the month.

However, in an attempt to address the concerns of transmission customers, particularly third party suppliers, to obtain monthly billing information as soon as possible, and after discussions with customers, Illinois Power implemented a process whereby an estimated invoice for the previous month is calculated and distributed to transmission customers at the beginning of the succeeding month. Once the necessary billing data for the month has been collected for all 21 billing cycles for all retail load taking delivery services and is reviewed for accuracy and any metering-related issues, it is released for final billing.

18. Q. What is your response to BOB's assertion that it is unreasonable for the Commission to allow IP to keep the transmission policies, practices and tariff provisions BOB have complained about in place until the start of MISO "Day 2"? (BOB Testimony, pp. 29-30)

A. As I have explained, Illinois Power's transmission policies, practices and tariffs that BOB have criticized are reasonable, and BOB's criticisms and proposals are unreasonable, unachievable or both. Therefore (even assuming that this Commission could order IP to change its FERC-jurisdictional transmission tariffs, policies and practices), there is no reason to do so before the start of MISO Day 2, even if MISO Day 2 were to be delayed. Further, even if the start of MISO Day 2 were to slip, it would likely be a matter only of months. There is no justification for Illinois Power to implement numerous changes to its transmission tariffs, policies and practices, as BOB have requested, on what would clearly be only an interim basis.

19. Q. Please respond to BOB's concern that a RES is unable to obtain all PPO pricing elements used in the IP service area and that IP does not give timely responses to RESs and customers "in providing the PPO calculations which determines their Customer Transition Charge ("CTC") and PPO eligibility". (BOB Testimony, pp. 30-31)

A. First, PPO calculations do not determine a customer's transition charge nor the customer's PPO eligibility. It is the CTC that determines that customer's PPO eligibility (i.e., the customer must have a non-zero CTC in order to be eligible for PPO service). Second, Illinois Power has published CTCs without fail pursuant to the schedule established in our Commission-approved tariff. The same is true with respect to MVI values which do determine a customer's PPO price and are also an input to the customer's CTC. Therefore, I do not understand what the delay is that BOB are complaining about, unless they are complaining about the schedules and time frames established in IP's Commission-approved Rider TC and Rider MVI tariffs. BOB's complaint that a RES is unable to obtain all PPO pricing elements relates, I assume, to the fact that IP will not release customer-specific PPO pricing studies and calculations to a RES without the customer's authorization. As I will discuss in greater detail later in this testimony, there are valid, customer-driven reasons for this limitation.

20. Q. BOB complain that the period in which IP customers can elect to contract for a CTC based on a multi-year market value and the subsequent period within which

the customer must elect PPO service are too short and do not give the customer enough time to "shop" nor the RESs enough time to market to these customers. (BOB Testimony, pp. 31, 32-34) Do these concerns warrant any changes in IP's tariffs?

A. No. The provisions of which BOB complain are provisions in IP's Commission-approved tariffs that resulted from litigated proceedings before the Commission and settlement negotiations in those proceedings, within the last several years. In fact, various intervenors including Constellation New Energy and Peoples Energy Services, BOB's employers, were parties to a memorandum of understanding with IP in Docket 02-0672 which was filed with the Commission that led to the pertinent tariffs which were approved by the Commission.

As BOB point out at line 696 of their testimony, "time is of the essence, markets change . . . ." The multi-year market value-based CTC option is a fixed-price option that IP offers for limited time periods, while markets and conditions change. BOB is asking that IP be required to maintain fixed price offerings for longer periods while other market participants such as the RESs are free to continually change their pricing. This request is unreasonable. I do not regard this as a competitive issue; rather, from IP's perspective it is an issue of exposure to risk by virtue of having to hold open fixed price offerings for an extended period while market pricing may be changing.

I note in any event that there is only one remaining opportunity for customers to elect a multi-year market value and associated CTC prior to the end of the mandatory transition period, namely, in January-February 2005 for the 2005-2006 period.

21. Q. Please explain the timeline for customers to elect a multi-year market value and multi-year market value-based CTC in the January-February 2005 window.

A. A customer may provide notice to IP that the customer is electing a multi-year market value any time up to seven business days before the customer's desired effective date. The earliest allowed effective date is December 30, 2004, which would require notice to IP by December 21, 2004. CTCs based on the multi-year market values will be available on December 23, 2004. A customer may provide notice that it is electing a multi-year market value as late as February 18, 2005, for an effective date of March 1, 2005. Thus, this schedule provides a window of 58 days after CTCs based on the corresponding multi-year market values become available during which a customer can elect to take the multi-year market value option.

22. Q. BOB also complain that Illinois Power requires customers whose CTCs are individually calculated and that elect a CTC based on a multi-year market value to execute both an "Agreement to Pay Transition Charges" and a "Multi-Year Market Value Contract" and that these contracts should be merged into a single form. (BOB Testimony, p. 34) Why does IP use two contracts?

A. The "Agreement to Pay Transition Charges", which I understand is authorized by statute (that is, the Public Utilities Act authorizes the utility to require a customer that receives an individual CTC calculation to sign a contract to pay the CTC), is used for any customer taking delivery services whose CTC is individually calculated. Illinois Power has many such contracts outstanding, because IP provides individual CTC calculations for those customers, among others, with maximum monthly demands greater than 100 kW or served at a delivery voltage of greater than 600 volts, which is a considerably more generous policy than the statutory requirement to provide individual CTC calculations for customers 1 MW or larger. A relatively small number of the customers that receive individually-calculated CTCs also elect a multi-year market value-based CTC, so IP created a separate contract form to cover the multi-year market value-based option. In any event, I would not consider it a good use of resources to develop a new, combined contract form, which would likely ultimately be used by only a small number of customers, when there is only one more occasion during the mandatory transition period for customers to elect a multi-year market value.

23. Q. What is your response to BOB's complaint that Illinois Power should make CTC and PPO values available on its website for all (presumably nonresidential) customers, not just for customers smaller than 1 MW? (BOB Testimony, p. 31)

A. With respect to CTC information, the Commission's Interim Order in Docket 00-0494 (the "uniformity" docket) approved a stipulated agreement among the parties pursuant to which CTCs for customers larger than 1 MW would be provided by the utility to a RES only if the utility received a release from the customer. Specifically, the stipulation adopted by the Interim Order states:

> Utilities providing CTCs on their websites will provide those CTC values that are individually calculated to registered RESs having customers' account and meter numbers for customers with demand of less than 1 MW. Utilities will not provide such values on their websites to any person other than the customer for customers with

> demand of 1 MW or above without explicit customer authorization.

Signatories to the stipulation included the IIEC (representing large nonresidential customers), MidAmerican Energy Company, Peoples Energy Services Corporation and NewEnergy Midwest, LLC (a predecessor company of Constellation New Energy, Inc.). Illinois Power continues to abide by this order. With respect to PPO information, PPO prices (market values) are available to RESs for all nonresidential customers (PPO is not available to residential customers), so I do not understand BOB's concern.

24. Q. What is your response to BOB's complaint that Illinois Power should make the "PPO Calculator" available to RESs without customer authorization? (BOB Testimony, p. 31)

A. The PPO Calculator is a service that Illinois Power makes available to its customers. IP has no obligation to make this service available. The PPO Calculator utilizes the applicable MVI values and CTC values and the customer's last 12 months of actual usage data to create a comparison of a bundled customer's existing current charges and the estimated current PPO charges for the same load pattern. In some cases, customers may wish that a RES that is a potential supplier to the customer not have access to the PPO Calculator (or know what the PPO pricing to the customer would be), so that the RES provides its best offer to the customer, not merely an offer than undercuts the PPO pricing by a small amount. Illinois Power makes data and tools available to the customer and to RESs to the extent that the customer wants RESs to have customer-specific data and tools. IP agrees with BOB's statement that access to the PPO Calculator should not be "regulated by the utility" (BOB Testimony, p. 31) – it should be regulated by the customer whose PPO charges it would be used to calculate.

25. Q. Do you agree with BOB's position that if a RES has a customer's account number and a single meter number, the utility should allow the RES to access the customer's usage data for all other meters associated with that account? (BOB Testimony, p. 31)

A. No. The customer may wish the RES to have access to data on some meters but not on other meters. Illinois Power would have no way of knowing the customer's wishes in this regard except by relying on the customer authorization to release the data for each meter. I note that under Section 16-104(e) of the Public Utilities Act, a customer can elect to place only a portion of its power and energy requirements on delivery services (i.e., RES supply or PPO) while leaving the remainder on the utility's bundled tariffs, and the customer may desire to accomplish this by placing only certain meters on RES supply. As I noted earlier, Illinois Power attempts to provide RESs with access to all customer-specific information that the customer authorizes the RES to have, but not information the customer has not authorized to be released.

26. Q. BOB want Illinois Power's charges for customer monthly usage data ($1 per download), the PPO Calculator ($4.50/$12.50) and the interval summary data charge ("8760 charge") ($20 plus $8 per meter) to be eliminated. (BOB Testimony, pp. 32, 34-35) Do you agree?

A. No. First, the Public Utilities Act (Section 16-122(b)) authorizes the utility to charge a reasonable fee for customer billing and usage data. Second, the charges that BOB wishes to have eliminated are Commission-approved charges that are set forth in IP's electric tariff (Standard Terms and Conditions, Sections 4(g) and 4(i)). These charges were approved by the Commission in IP's last delivery services tariff case, Docket 01-0432. Obviously, IP incurs costs to provide these services, and by these charges, costs are recovered directly from the party (a RES or the customer) actually using the services. Elimination of the charges would mean that IP would ultimately have to recover the costs of these services through its generally applicable rates to all of its customers. In any event, the Commission should not require IP to change some of its charges outside the context of a rate case and without reviewing other associated prices, terms and conditions.

27. Q. Please explain what "8760 data" is as referred to in your previous answer.

A. "8760 data" is hourly interval usage data for a 12 month period (8,760 hours).

28. Q. BOB indicate that in some instances IP has not provided "8760 data" for a full twelve months when requested. (BOB Testimony, p. 34) Is this correct?

A. Yes, for a period of time a technical problem existed that on occasion prevented a full 12 months of data from being transmitted electronically. In such instances IP immediately provided the missing data manually. The technical problem was corrected as of May 26, 2004.

29. Q. BOB complain that IP will not allow a "billing agent" to act as such only for a customer's electric service, but rather requires the billing agent to act as such for both the customer's electric service and gas service (if any). (BOB Testimony, pp. 32, 35-36) Are their concerns valid?

A. Their concerns are certainly overstated. If a retail customer is taking power and energy from a RES, the RES can obtain the billing data for only the customer's electric service by electing the Single Billing Option ("SBO") which is provided for in IP's delivery services tariffs. Under the SBO, the RES does not have to handle the customer's gas service billing, which IP will continue to bill directly to and collect from the customer. The only scenario in which IP does not split the electric and gas bills is where the RES (or other third party) is acting solely as a billing agent for the customer. In our experience, this situation typically arises when a RES is acting only as a billing agent and not as the supplier, places the customer on IP's PPO service, but seeks to be able to issue a bill directly to the customer from the RES for this service, rather than having the customer receive IP's bill. I note also that IP's billing system is designed to produce and send (mail) a combined electric and gas service bill to the customer and to collect customer payments applicable to both accounts, and that the efficiencies inherent in this combined billing system are reflected in IP's cost of service and tariffed rates. BOB's testimony does not indicate that their companies are willing to pay a charge to cover the incremental costs IP would incur by splitting a customer's electric and gas service bills into separate billings.

30. Q. As a final point, BOB state that IP's "customer notification requirements should be streamlined in order to support choice" and that "Under IP's Rate 24, customers are required to provide twelve (12) months notice of intent to elect delivery services. We believe a sixty (60) or ninety (90) day notice is more appropriate." (BOB Testimony, p. 36) What is your response?

A. The manner in which BOB present this point is extremely disingenuous. The tariff provision of which they are complaining is not a notice requirement to elect delivery service but rather a notice requirement to terminate the customer's SC 24 contract. Specifically, Section 1 of IP's SC 24 requires that the customer enter into a written contract for this service offering and Section 4(b) states: "The term of any contract shall be automatically extended from year to year with the privilege of either party to terminate the contract at the end of the Primary Term or thereafter on not less than 12 months written notice." BOB also fail to note that this issue has been raised in at least two previous dockets since passage of the Customer Choice Law but has not been accepted by the Commission. Most recently, in Docket 01-0432, IP's last delivery services tariff case, the IIEC made this same proposal. The Commission rejected it, stating:

> With regard to its proposal to allow SC 24 customers to provide a 30-day notice of intent to terminate service, IIEC fails to adequately explain why customers switching to delivery services should be treated differently from customers wishing to terminate SC 24 service but not switch to delivery services. In view of the disparate treatment IIEC's proposal would cause between various customers that may wish to leave SC 24, the Commission does not find IIEC's arguments that such a proposal would enhance competition compelling. (Order in Docket 01-0432 (March 28, 2002), p. 125)

SC 24 is an optional service offering that provides larger nonresidential customers lower prices than does SC 21 (which does allow for termination on 30 days notice to take delivery services) in return for the customer's commitment to (i) maintain a specified load factor and (ii) enter into a longer term contract, thereby providing decreased risk and increased certainty for IP. The Commission should not require

IP to change a provision of this tariff outside the context of a rate case and without reviewing all the rates, terms and conditions of the tariff.

Most importantly, Illinois Power effectively allows customers to decide to terminate their SC 24 contracts in order to take delivery services (or any other available service option) on 60 days notice. As recognized by the Commission in the Docket 01-0432 Order (p. 125), IP allows a customer taking service on SC 24 to give its 12 months notice to terminate service under SC 24, but then to rescind that notice at any time up to 60 days prior to the date of termination. Thus the SC 24 customer, by giving notice to terminate 12 months prior to the end of its contract term, can effectively wait until 60 days prior to expiration of the contract to decide whether to remain on SC 24 or to take delivery services.

31. Q. Are any of the IIEC companies that have intervened in this case taking electric service on IP's bundled tariffs?

A. Yes. Of the 14 IIEC intervenors in this case, five are taking service on IP's bundled tariffs and one has a portion of its service on the bundled tariffs and a portion on delivery services.

32. Q. Does this conclude your prepared rebuttal testimony?

A. Yes, it does.